Air Quality Permitting
Statement of Basis

August 3, 2005

Permit to Construct No. P-050301
and
Tier I Operating Permit No. T1-050308

Basic American Foods
Blackfoot, ID

Facility ID No. 011-00012

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PUBLIC COMMENT DRAFT

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Acronyms, Units, and Chemical Nomenclatures

AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BAF	Basic American Foods
Btu	British thermal unit
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
CMS	Continuous Monitoring Systems
COMS	Continuous Opacity Monitoring System
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
gr	grain (1 lb = 7,000 grains)
HAPs	Hazardous Air Pollutants
IDAPA	A numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pound per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMscf	million standard cubic feet
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
Rules	*Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01*
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
TPY or T/yr	Tons per year
UTM	Universal Transverse Mercator
VOC	volatile organic compound
ug/m^3	micrograms per cubic meter

Public Comment / Affected States / EPA Review Summary

A 30-day public comment period for the BAF Blackfoot facility draft Tier I operating permit will be held in accordance with IDAPA 58.01.01.364, *Rules for the Control of Air Pollution in Idaho*.

IDAPA 58.01.01.008.01 defines *affected states* as: *"All states: whose air quality may be affected by the emissions of the Tier I source and that are contiguous to Idaho; or that are within 50 miles of the Tier I source."*

A review of the site location information included in the permit application indicates that the facility is not located with 50 miles of a state border, however, it is located within 50 miles of the Shoshone-Bannock Tribes. Therefore, the Shoshone-Bannock Tribes will be provided an opportunity to comment on the draft Tier I operating permit.

Summary of Comments:

None, as of July 12, 2005

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01.200, *Rules for the Control of Air Pollution in Idaho (Rules),* for issuing permits to construct (PTC) and IDAPA 58.01.01.300 for issuing Tier I operating permits..

2. FACILITY DESCRIPTION

The Basic American Foods (BAF) Blackfoot Plant includes a food dehydrating plant and a co-located research and development laboratory related to vegetable dehydrating and product development. The Blackfoot plant produces dehydrated food products using a variety of drying and dehydration processes. Products are dried by contact with heated air. Drying air is heated either by direct-firing with natural gas or indirectly using steam heat exchangers. Steam for plant operations is provided by Boiler Numbers 1, 2 and 3.

Note that BAF identifies the Blackfoot Plant boilers differently for plant operating purposes than the designations used in previous permits and in the current application. To minimize confusion, BAF has requested that the Department of Environmental Quality (DEQ) use the plant boiler numbering system. This permit and statement of basis use the revised numbering system. The revisions in boiler numbering are as follows:

Table 2.1 BOILER DESIGNATIONS

Previous Designation	Current Designation
Boiler 6	Boiler 2
Boiler 7	Boiler 3
Boiler 8	Boiler 1

3. FACILITY / AREA CLASSIFICATION

The BAF Blackfoot Plant is a major facility under the Title V program, as defined under IDAPA 58.01.01.008.10, because the facility emits or has the potential to emit a regulated air pollutant in amounts greater than 100 tons per year. The BAF Blackfoot Plant is not a major facility under the PSD/NSR program as defined under IDAPA 58.01.01.205.01 (40 CFR 52.21(b)(1)). The AIRS classification for this facility is “A” and the AIRS data entry table is provided in Appendix A.

The facility is located within AQCR 61 and UTM zone 12. The facility is located in Bingham County which is designated as attainment or unclassifiable for all criteria pollutants (CO, NO_x, SO_2, lead, and ozone). The Blackfoot Plant SIC is 2034 which represents establishments primarily engaged in artificially dehydrating fruits and vegetables, including “potato flakes, granules, and other dehydrated potato products.”

4. APPLICATION SCOPE

4.1 Scope Summary

On February 4, 2005 DEQ received an application from BAF to modify Permit to Construct No. P-040300, issued March 22, 2004, as amended by Consent Order between Idaho DEQ and Basic American Foods in Case No. E-010007, dated August 20, 2004. The changes requested by this application involve only Boilers 1 and 2. No physical changes or changes in method of operation are proposed for Boiler 3. Changes are proposed as follows:

- Modify Boiler 2 for combustion of higher sulfur fuel including No. 6 residual oil
- Increase the allowable sulfur content of residual oil for Boiler 1 from 1.5% to 1.75%
- Increase the annual quantity of residual oil that may be combusted in Boiler 1
- Provide wet scrubbing treatment of the exhausts from Boilers 1 and 2 when combusting fuel oil to meet NSPS requirements for Boiler 2, and to reduce emissions of PM_{10}, SO_2, soluble acid gases and TAPs from Boilers 1 and 2
- Install ducting to merge the exhausts from Boilers 1 and 2 when fuel oil is combusted
- Replace limitations on hours of operation when combusting oil with fuel consumption limits for Boilers 1 and 2
- Establish enforceable limits on boiler house PTE so the entire facility remains minor for PSD purposes
- Revise boiler emission limits, operating, monitoring, recordkeeping and reporting requirements commensurate with this modification

4.2 Application Chronology

February 4, 2005	DEQ received the PTC application
February 18, 2005	DEQ received a 15-day pre-permit construction approval request
March 4, 2005	DEQ determined the PTC application was complete
March 9, 2005	DEQ approved the 15-day pre-permit construction approval request
March 15, 2005	DEQ received a Tier I Significant Permit Modification application
April 25, 2005	DEQ received amended application materials
April 27, 2005	DEQ received proposed PTC conditions from BAF
May 4, 2005	DEQ received a proposed Statement of Basis from BAF
June 7, 2005	DEQ received revisions to the TAPs compliance demonstration
June 24, 2005	DEQ issued a draft PTC and Statement of Basis to BAF for review
July 8 & 11, 2005	BAF provided comments regarding the draft permit

5. PERMIT ANALYSIS

This section of the Statement of Basis describes the regulatory requirements for this PTC action.

5.1 Equipment List

Table 5.1 lists all sources affected by this permit modification.

Table 5.1 SUMMARY OF REGULATED SOURCES

Source Description	Emissions Control(s)
Boiler 1 (formerly Boiler 8): Manufacturer/Model: Murray Rated Heat Input: 57 MMBtu/hr Steam Rate: 45,500 lb/hr Fuels: natural gas, distillate and residual fuel oils	Wet Scrubber, Good Combustion Control
Boiler 2 (formerly Boiler 6): Manufacturer/Model: Johnson "509" Series, Model TF1800 – 3HG250S Rated Heat Input: 75.4 MMBtu/hr Steam Rate: 62,100 lb/hr Fuels: natural gas, distillate and residual fuel oils	Wet Scrubber, Good Combustion Control
Boiler 3 (formerly Boiler 7): Manufacturer/Model: Springfield Model 52 Rated Heat Input: 39 MMBtu/hr Steam Rate: 30,000 lb/hr Fuels: natural gas and low sulfur (0.05 wt %) distillate fuel oil	Good Combustion Control

5.2 Emissions Inventory

BAF's emissions inventory calculations take consideration of each of the following boiler firing scenarios and the project's estimated emissions are based on the scenario that yields the highest emissions for each pollutant:

- Firing Boilers 1 and 2 with No. 6 oil at reduced daily and annual heat input rates.
- Firing Boiler 2 on No. 2 oil at full firing rates for 8760 hours per year, and operating either Boiler 1 or Boiler 3 as a second boiler, selecting the particular combination of boiler and fueling option that yields the highest emissions for each pollutant.
- Firing Boiler 2 on natural gas at full firing rates for 8760 hours per year, and operating either Boiler 1 or Boiler 3 as a second boiler, selecting the particular combination of boiler and fueling option that yields the highest emissions for each pollutant.

Different scenarios were found to result in the highest estimated emissions. For example, natural gas firing is associated with the highest estimates for CO and VOC emissions, whereas No. 6 oil firing yields the highest estimated emissions of NO_x, PM_{10}, and SO_2.

The changes in emissions associated with this permit modification were estimated by the applicant and checked by DEQ. To determine the changes in criteria emissions for this project, the maximum emissions estimates provided in Tables 6 and 7 of the application were compared to the emission limits specified in the Appendix of PTC No. P-040300 issued on March 22, 2004. The criteria emissions changes are summarized below in Table 5.2. Estimates are only provided for Boilers 1 and 2, and not for Boiler 3, because emissions from Boiler 3 remain unchanged as part of this project. For convenient reference, copies of Tables 6, 7, 12, F-1, F-2, and F-3 from the application and the emission limits table in PTC No. P-040300 (March 22, 2004) are provided in Appendix B in addition to the DEQ emission estimate worksheets for this modification.

Table 5.2 EMISSION INVENTORY – MODIFICATION CHANGES

Pollutant	Hourly Emission Rate (lb/hr)					Annual Emissions (T/yr)				
	Existing[1]		Proposed[2]		Change	Existing[1]		Proposed[2]		Change
	Boiler 1	Boiler 2	Boiler 1	Boiler 2		Boiler 1	Boiler 2	Boiler 1	Boiler 2	
CO	1.3	3.3	4.6	6.1	6.1	4.5	8.4	19.9	26.5	33.5
NO_x	12.5	1.8	23.1	38.8	47.6	46.4	4.6	88.6	109.4	147
PM_{10}	3.3	0.1	2.1	3.6	2.3	12.1	0.3	8.2	10.1	5.9
SO_2	56.8	0.0	16.9	28.4	-11.5	205	0.1	64.8	80.1	-60.2
VOC	0.2	0.2	0.3	0.4	0.3	0.3	0.5	1.3	1.7	2.3

1. Existing emission based on estimated current emissions.
2. Proposed emission limits considering controls, restrictions on operations, and values for which compliance with applicable rules was demonstrated.

Table 5.3 summarizes total estimated facility-wide annual emissions from non-fugitive emissions units after the modification.

Table 5.3 EMISSION INVENTORY – ENTIRE FACILITY[1]

CO (T/yr)	NO_x (T/yr)	PM_{10} (T/yr)	SO2 (T/yr)	VOC (T/yr)
231	235	138	160	6.6

[1] Excluding plant heater fugitive emissions (per 40 CFR 52.21(b)(1)(iii))

The increase in toxic air pollutant (TAP) emissions for this modification were also estimated by BAF and checked by DEQ. For this project, Table 5.4 provides a list of each TAP for which the estimated emissions increase is greater than the screening emission level (EL) listed in IDAPA 58.01.01.585 or 586. As described above, the maximum TAP increase is based on the boiler firing scenario that yields the highest emissions for each pollutant. For details, refer to application Tables 18-21 which are included in Appendix B. Also, refer to the modeling section or IDAPA 58.01.01.210 in the regulatory analysis section of this document.

Table 5.4 SUMMARY OF TAP EMISSION INVENTORY

TAP	EL (lb/hr)	Maximum Emission Rate (lb/hr)	
		Uncontrolled	Project Increase
Arsenic	1.50E-06	8.57E-04	1.19E-04[a]
Beryllium	2.80E-05	3.73E-04	1.80E-04[a]
Cadmium	3.70E-06	3.73E-04	4.34E-05[a]
Chromium (VI)	5.60E-07	1.61E-04	2.08E-05[a]
Nickel	2.70E-05	5.48E-02	8.14E-03[a]
Polycyclic Organic Matter (POM)	2.00E-06	7.79E-06	5.06E-06[a]
Formaldehyde	5.10E-04	4.36E-02	3.04E-02[a]
Chloride (as HCl)	5.00E-02	2.51E-01	---[b]
Vanadium (as V2O5)	3.00E-03	3.69E-02	5.54E-03[a]

[a] Project increase is greater than EL.
[b] No increase in emissions.

5.3 Modeling

Emissions increases associated with this project were modeled by the applicant in accordance with the State of Idaho Air Quality Modeling Guidance to demonstrate compliance with the NAAQS and TAP requirements under IDAPA 58.01.01.203. The applicant's analysis was reviewed and found to be consistent with DEQ methods and procedures. Details are provided in the Memorandum from Kevin Schilling to Dan Pitman which is included in Appendix C.

5.4 Regulatory Review

This section describes the regulatory analysis of the applicable air quality rules.

IDAPA 58.01.01.201 ....Permit to Construct Required

A permit to construct is required. This project does not qualify under the PTC exemption requirements. On this basis, BAF has applied for a PTC modification.

IDAPA 58.01.01.203.02 ....Demonstration of Preconstruction Compliance with NAAQS

Compliance with the NAAQS has been demonstrated in the permit application. Refer to the Modeling Section above and Appendix C for details.

IDAPA 58.01.01.205 ....Permit Requirements for New Major Facilities or Major Modifications in Attainment or Unclassifiable Areas

BAF is not a major facility for purposes of the NSR/PSD program as defined under IDAPA 58.01.01.205.01 [40 CFR 52.21(b)(1)(i)(a), (b) and (c)], as described below.

Because the facility is not on the list of sources stationary sources specified in 40 CFR 52.21(b)(1)(i) (i.e., the sources that have a PSD threshold of 100 TPY), the PSD threshold for the facility is 250 TPY. From Table 5.3 above, the pollutants with the highest PTE (at this facility are CO (231 TPY), NO_x (235 TPY) and SO_2 (160 TPY). These PTE estimates exclude fugitive emissions such as the plant heaters per 40 CFR 52.21(b)(1)(iii).

This boiler modification project does not constitute a "major modification" for purposes of the NSR/PSD program. The major modification definition given by 40 CFR 52.21(b)(2) does not apply since BAF is not a "major facility", for purposes of the NSR/PSD program, as described above.

IDAPA 58.01.01.209.05 ....PTC Requirements for Tier I Sources; Tier I Modification

For Boiler 1, the new and revised applicable requirements contained in the final PTC may be incorporated into the Tier I permit during renewal in accordance with IDAPA 58.01.01.209.05.a.iv. BAF may construct the modifications to Boiler 1 prior to issuance of the PTC per IDAPA 58.01.01.209.05.a.ii and 213. BAF may commence operation of Boiler 1 with the modifications in place after issuance of the PTC so long as it does not violate any terms or conditions of the existing Tier I operating permit and such operation will comply with Subsection 380.02 per IDAPA 58.01.01.209.05.a.iii.

Regarding Boiler 2, the Tier I operating permit is being modified concurrently with issuance of this PTC because the modifications to Boiler 2, allowing the combustion of residual oil, require that the Tier I permit be modified before the modified operations begin. BAF may not commence operations of Boiler 2 using residual oil, nor combust distillate oil or natural gas in any manner not allowed by the existing Tier I permit until issuance of the modified Tier I permit. BAF has submitted an application for modification of the Tier I permit to incorporate the provisions of this PTC. Concurrent issuance of the Tier I and PTC will be conducted in accordance with 58.01.01.209.05.b.

IDAPA 58.01.01.203.03, 210 ....Demonstration of Preconstruction Compliance with Toxic Standards

Emission increases of TAPs from the project have been evaluated to demonstrate compliance with the TAP standards under IDAPA 58.01.01.210. The TAP were evaluated with regard to the increase in TAP emissions resulting from the modification. Most of the TAP increases were shown to be in compliance with IDAPA 58.01.01.210.05 since the uncontrolled hourly emissions rate would be less than the applicable screening emission level (EL) listed in Sections 585 and 586.

Table 5.4 above, lists each TAP increase which exceeds the EL. For the TAPs which exceed the EL, all except nickel were shown to be in compliance with IDAPA 58.01.01.210.06 since the uncontrolled ambient concentration at the point of compliance is less than the applicable acceptable ambient concentration listed in Sections 585 and 586. Nickel was shown to be in compliance with IDAPA 58.01.01.210.08 since the controlled ambient concentration at the point of compliance is less than the applicable acceptable ambient concentration listed in Sections 585 and 586. For nickel, an emission limit was included in the PTC as required by IDAPA 58.01.01.210.08.c.

IDAPA 58.01.01.213 ....Pre-Permit Construction

On February 18, 2005, DEQ received a 15-Day Pre-permit Construction Approval Application submitted by BAF pursuant to IDAPA 58.01.01.213. By letter dated March 9, 2005, DEQ approved BAF's pre-permit construction application.

IDAPA 58.01.01.380, 382 ....Changes to Tier I Operating Permits

A Tier I permit revision is required for changes that are not addressed or prohibited by the Tier I operating permit if such changes are modifications under any provision of Title I of the Clean Air Act. The modifications to Boiler 2 allowing it to combust residual oil or to combust distillate oil with sulfur content greater than 0.05 weight percent (wt%) or for periods longer than 1440 hrs/year are subject to 40 CFR 60, Subpart Dc. Accordingly, a Tier I permit revision is needed for these modifications to Boiler 2. On February 15, 2005, BAF submitted a properly certified request for a significant modification of the Tier I permit to incorporate provisions of this PTC.

IDAPA 58.01.01.590 ....Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

60.40c, Applicability. The provisions of Subpart Dc apply to Boiler 2 since the a modification of the boiler would occur after June 9, 1989 and it has a maximum design heat input capacity that is less than 100 but greater than 10 MMBtu/hr. Subpart Dc does not apply to Boiler 1 since it was installed and equipped with burners to fire residual oil prior to the June 9, 1989 cutoff date for applicability of this subpart. Details are provided below regarding applicability of Subpart Dc to Boiler 2.

The Boiler 2 modification project would be a modification under 60.14(a) since it is a physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. It is noted that the exception to the modification under 60.14(e)(4) does not apply since the existing facility was not designed to accommodate the alternative fuel (fuel oil) prior to the date the standards under Subpart Dc became applicable to the source type (September 12, 1990). Per 60.40c(b), it is noted that delegation of the requirements of 60.48c(a)(4) are retained by the EPA Administrator with regard to emerging control technology. Also, 60.40c(c) and (d) do not apply since the boiler is not used for combustion research.

60.42c, Standard for Sulfur Dioxide. Under the SO_2 emission standard given by 60.42c(d), Boiler 2 shall not emit SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or as an alternative the oil combusted shall not contain greater than 0.5 wt% sulfur. Also per 60.42c(d), the percent reduction requirements for SO_2 are not applicable to the boiler. Compliance with the fuel oil sulfur limits and emissions limits (but not the percent reduction requirements) given by 60.42c(d) shall be determined on a 30-day rolling average basis per 60.42c(g). Under 60.42c(h), when distillate oil is fired, the NSPS rules allow compliance with the NSPS emission limits or fuel oil sulfur limits to be determined based on a certification from the fuel supplier, as described under 60.48c(f)(1); however, the requirements of 60.42c(h) were not included in the permit because a CEMS must be used for SO_2 monitoring for all fuel oils to avoid triggering the CAM requirements (see 40 CFR 64 below). The SO_2 emission limits and fuel oil sulfur limits apply at all times, including periods of startup, shut down, and malfunction per 60.42c(i).

It is noted that only the heat input supplied to the affected facility from the combustion of oil is counted under this section. No credit is provided for the heat input to the boiler from wood or other fuels or for heat derived from exhaust gases from other sources per 60.42c(j). The requirements under 60.22c(a), (b), (c), (e), and (f) do not apply to the boiler since it will not combust either of the following: coal; or oil in combination with any other fuel.

60.43c, Standard for Particulate Matter. The PM emission limits under 60.43c(a) and (b), expressed in terms of ng/J (lb/MMBtu) do not apply since the boiler does not combust coal or wood. The opacity standard under 60.43c(c) applies, and it applies at all times, except during periods of startup, shut down, and malfunction per 60.43c(d).

60.44c, Compliance and Performance Test Methods and Procedures for SO_2. For Boiler 2, the following requirements apply: 60.44c(a), (b), (c), (d), (g), (h), and (j). However, 60.44c(h) was not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. The following requirements do not apply since the boiler does not combust coal, it does not combust oil in combination with other fuels, and the percent sulfur reduction requirement does not apply: 60.44c(e), (f), and (i).

60.45c, Compliance and Performance Test Methods and Procedures for PM. In accordance with 60.45c(a) and (a)(8), BAF shall conduct an initial performance test as required under 60.8 and shall conduct subsequent performance tests as requested by the EPA Administrator to determine compliance with the standards using the following procedures and reference methods: Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions. The requirements of 60.45c(a)(1) through (7) do not apply since the boiler is not subject to the PM emission limit/concentration standards under 60.43c. The requirements under 60.45c(b) do not apply since 60.43c(b)2) does not apply.

60.46c, Emission Monitoring for SO_2. For Boiler 2, the requirements under 60.46c(a) through (f) apply except for the following. The requirements of 60.46c(e) were not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. Since the boiler is not subject to the percent reduction requirements for SO_2, BAF is not required to do the following: measurement of SO_2 concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO_2 control device as described under 60.46c(a); meet the CEMS span requirements of 60.46c(c)(3).

60.47c, Emission Monitoring for PM. The continuous Opacity Monitoring System (COMS) requirements under 60.47c(a) and (b) apply.

60.48c, Reporting and Recordkeeping Requirements. The requirements under 60.48c(a) through (g), (i), and (j) apply except for the following. The requirements of 60.48c(f) were not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. Since the boiler does not fire coal and it is not subject to the percent reduction requirements for SO_2, the requirements of 60.48c(e)(3) and 60.48c(f)(3) do not apply. 60.48c(f)(2) does not apply since 60.42c(h)(2) does not apply. 60.48c(h) does not apply since there are no limits on the annual capacity factor for any fuel or mixture of fuels.

40 CFR Part 64..Compliance Assurance Monitoring (CAM)

Boilers 1, 2, and 3 are exempt from the requirements under 40 CFR Part 64. Boiler 1 does not meet the applicability criteria and Boilers 1 and 2 are exempt under 64.2(b) since the Tier I permit will require the use of an SO_2 CEMS (i.e., a continuous compliance determination method) when combusting residual or distillate fuel oil. Details are provided below.

Applicability is evaluated on a pollutant-specific basis for each emissions unit as follows:

- Under 64.2(a)(1), Boilers 1, 2, and 3 are subject to the following emission limitations or standards: NAAQS for SO_2 and PM_{10}; IDAPA 58.01.01.676 (fuel burning equipment grain loading standard) for PM; and NSPS for SO_2 for Boiler 2.
- Under 64.2(a)(2), Boilers 1 and 2 each use a wet scrubbing control device to achieve compliance with the emission limitations and standards listed above for SO_2, PM_{10} and PM. Part 64 does not apply with regard to any other regulated air pollutants because the boilers do not use a control device to achieve compliance with any of the emission limitations or standards for those pollutants. Boiler 3 is not applicable to CAM for any pollutant since it does not use a control device to achieve compliance with the emission limits or standards.
- The criteria under 64.2(a)(3) is evaluated as follows:
  - First, the lowest pound per hour emission rate that would result in emissions over 100 TPY is determined as follows, based on operations of 8760 hr/yr:
  - 100 tons/yr = (x)(8760 hr/yr)(ton/2000 lb)
  - x = (100 tons/yr)(yr/8760 hr)(2000 lb/ton) = 22.8 lb/hr
  - Second, applicable sources are identified using the uncontrolled emission rates in Table 6 of the application. The only “pollutant-specific emissions units” which utilize emissions controls and which have “potential pre-control device emissions” greater than 100 TPY (i.e., 22.8 lb/hr) are Boilers 1 and 2 when firing either distillate or residual oil. Specifically, Boilers 1 and 2 are pollutant specific emissions units only with regard to SO_2 (i.e., not with regard to PM or PM_{10}) and only when firing either distillate or residual oil.
- The CAM exemption under 64.2(b)(1)(i) does not apply for Boiler 2 since NSPS Subpart Dc was proposed prior to November 15, 1990.
- The CAM exemption under 64.2(b)(1)(vi) applies to Boilers 1 and 2 with regard to SO_2 as long as the Tier I permit (i.e., Part 70 permit) specifies that an SO_2 CEMS or Method 6b (i.e., continuous compliance determination methods per 40 CFR 60 Subpart Dc) must be used whenever distillate or residual fuel oil is combusted. Distillate oil monitoring based on fuel sampling and receipts, which is allowed under 60.42c(g) and (h), are not considered to be a “continuous” compliance determination methods, and for this reason they are not included in the permit as allowable options under the NSPS requirements. If BAF later desires to use fuel sampling or receipts instead of the CEMS for monitoring distillate oil, a PTC modification would be necessary; this exemption from Part 64 would no longer apply and the CAM requirements would need to be addressed as part of that modification.

IDAPA 58.01.01.591 ....40 CFR Part 61 and Part 63, NESHAP, MACT

No MACT or NESHAP rules apply because the Blackfoot Plant is not a major source of Hazardous Air Pollutant Emissions.

IDAPA 58.01.01.625 ....Visible Emissions

The opacity standard applies and it is included in the permit. Compliance will be demonstrated using the monitoring requirements that already exist in the Tier I permit and using the opacity compliance demonstration procedures required by 40 CFR 60 for Boiler 2.

IDAPA 58.01.01.676-677 ....Fuel Burning Equipment, Particulate Matter

IDAPA 58.01.01.676 applies to both boilers because the input heat capacity of each boiler is greater than 10 MMBtu/hr and both boilers were installed after October 1, 1979. Because of the potential for PM emissions from residual oil combustion, periodic testing of Boilers 1 and 2 using Method 5 is required by the permit to demonstrate compliance with this PM standard.

IDAPA 58.01.01.725-728 ....Sulfur Content of Fuels

The maximum allowable sulfur content of fuel is 0.5 weight percent for distillate oil and 1.75 weight percent for residual oil. These limits of fuel sulfur content are included in the PTC and in the Tier I permit. Compliance is demonstrated by following the monitoring requirements based on fuel supplier records.

IDAPA 58.01.01.776 ....Control of Odors

Odor control requirements apply and they are already included in the facility's existing Tier I Operating Permit.

Consent Order E-010007, August 20, 2004.........Paragraph 13 Requirements

The application was submitted to meet the requirements of paragraph 13 of the Consent Order.

5.5 PTC Permit Conditions Review

This section describes only PTC those permit conditions that have been revised, modified or deleted as a result of this permit action. All other permit conditions remain unchanged. Where permit condition numbers are given, these numbers correspond to the proposed modified PTC, unless stated otherwise.

Section 1. Permit to Construct Scope

Section 1, "Permit to Construct Scope," was updated to describe the modifications included in this permit.

Permit Condition 2.1

The emission rate limits for Boilers 1, 2 and 3 are revised to correspond to the information presented in the application which shows compliance with applicable rules such as the NAAQS. The limits are based on the worst case allowable operating scenario which is when Boilers 1 and 2 are fired at a reduced firing rate using No. 6 oil and Boiler 3 is not operated. Emission factors and stack combustion calculations when combusting fuel oil are the same for Boilers 1 and 2. Following is an example of how the combined annual boiler emissions limits were derived using information from Tables 6 and 7 of the application:

PM_{10} = 8.2 + 10.1 = 18.3 TPY
SO_2 = 64.8 + 80.1 = 145 TPY
CO = 19.9 + 26.5 = 46.4 TPY

Hourly emissions limits for Boiler 3 were not changed. Based on a review of controlled and uncontrolled emissions, the PM and VOC emission rate limits are not necessary for purposes of limiting PTE (e.g., for NAAQS, PSD threshold, etc.). Therefore, they are not included in the revised permit. The annual emissions limits for CO, PM_{10}, and SO_2 are based on "combined emissions" for all three boilers based on the estimates evaluated in the application.

Compliance with all of these emission limits is demonstrated by complying with the boiler fuel throughput limits, annual operating schedules, tune-up and maintenance requirements as given in Section 3 of the PTC, and by complying with the monitoring requirements in Section 4 of the PTC to record the hours of operation and fuel use on a daily and monthly basis. Additional, specific operating, testing, monitoring and recordkeeping requirements are also included in Sections 3 and 4 for demonstrating compliance with the SO_2 and NO_x emissions limits.

Permit Condition 2.2

Permit Condition 2.2 incorporates the NSPS limits on sulfur dioxide emissions that are applicable to Boiler 2.

Compliance is determined from the NSPS operating, monitoring, recordkeeping and reporting requirements as provided in Sections 3-5 of the permit including use of an SO_2 CEMS.

Permit Condition 2.3 and 2.5

The Permit Conditions were changed to clarify the opacity requirements. No substantive changes were made.

Permit Condition 2.4

This condition was added to the permit to clarify the applicability of 40 CFR 60.13(g). When the exhausts from Boiler 1 and 2 are merged ahead of a single scrubber, and both boilers are subject to the same emission standards, BAF may install the continuous monitoring systems on each effluent or the combined effluent from Boilers 1 and 2.

Permit Condition 2.6

An annual emission limit is provided for nickel as required by IDAPA 58.01.01.210.08.c. Compliance with the emission limit is demonstrated by complying with the boiler fuel throughput limits and annual operating schedules as given in Section 3 of the PTC, and by complying with the monitoring requirements in Section 4 of the PTC to record the hours of operation and fuel use on a and monthly and annual basis.

Permit Condition 2.7

The PM standard for fuel burning equipment applies to Boilers 1, 2, and 3. PM emissions are reduced by the wet scrubbing system when oil is fired in Boilers 1 and 2. Compliance with this permit condition is assured by requirements to install and operate a wet scrubber when combusting fuel oil and to do periodic PM performance testing as required in Sections 3 and 4 of the PTC.

Permit Condition 2.8

BAF requested that boiler NO_x emission be limited to 198 TPY so that the plant will not become a major source under the PSD program as defined in IDAPA 58.01.01.205.01 [40 CFR 60 52.21(b)1)]. When allowable boiler NO_x emissions of 198 TPY are added to the 36.7 TPY potential to emit (PTE) from other point sources at the facility (not counting plant heaters which are fugitive sources), the plant-wide NO_x PTE is 235 TPY (198 + 36.7 = 235). This value provides a safety margin of 15 TPY to keep the facility below the PSD threshold of 250 TPY.

A reasonable demonstration that plant-wide NO_x emissions will remain below 250 TPY (i.e., below 235 TPY) is provided by demonstrating that the 198 TPY limit for the boilers is being met. This approach is based on the following assumptions: the three boilers are the predominant NO_x sources at the facility; there are numerous other NO_x sources at the plant but they are each small in comparison to the boilers; the NO_x PTE for those small units was conservatively estimated (based on uncontrolled PTE at 8760 hr/yr) and it is reasonable to assume that actual operations/emissions from these sources will not exceed the PTE estimates. If an exceedance were to occur, it would most likely be caused by the boilers, therefore, a reasonable assurance that the 250 TPY threshold will not be exceeded is provided by using an emissions limit for the boilers plus operating, monitoring, recordkeeping and testing requirements to show compliance with this limit. This includes boiler fuel throughput limits, annual operating schedules, tune-up and maintenance requirements as given in Sections 3 and 4 of the PTC. These operating monitoring and recordkeeping requirements are adequate to make the boiler NO_x limit federally enforceable for PSD purposes.

As part of this compliance demonstration for the 198 TPY NO_x limit, periodic NO_x testing is required for Boilers 1 and 2 (the largest sources) but not for Boiler 3. The measured pound per hour emission rates for Boilers 1 and 2, and the PTE for Boiler 3 (i.e., 23 TPY) may be used to show compliance with the 198 TPY NO_x limit. Testing is not required for Boiler 3 because it is not changed as part of this modification and, more importantly, because the NO_x PTE is much smaller for Boiler 3 (i.e., 23 TPY) than the PTE is for Boilers 1 and 2 (i.e., 89 TPY and 109 TPY respectively). This is because Boiler 3 is fired primarily with natural gas, distillate oil use is limited, and residual oil use is prohibited.

Permit Condition 3.1

The demonstration of compliance with ambient air quality impact requirements incorporated assumptions from the application concerning the types of allowable fuels and the corresponding allowable sulfur contents for fuel oils. Permit Condition 3.1 incorporates these assumptions into the permit. The limits of 0.5 and 1.75 sulfur weight percent for distillate oil and residual oil combusted in Boilers 1 and 2 are the same as the maximum sulfur contents allowed by IDAPA 58.01.01, Sections 727 and 728.

Permit Condition 3.2, 3.3, and 4.12

The operating schedules and maximum fuel throughput rates included in the permit are the same as the assumptions used by BAF to demonstrate compliance with ambient air quality standards.

Operating limits are established for purposes of making the annual NO_x and CO emissions limits (for PSD threshold) and lb/hr PM_{10} emission limits (for NAAQS) federally and practically enforceable for Boilers 1, 2, and 3. Fuel throughput limits are established based on the quantity of residual fuel oil combusted that corresponds with the emissions limits under the worst case operating scenario (i.e., when Boilers 1 and 2 are fired with residual oil and Boiler 3 does not operate), as presented in the application. Fuel consumption limits for distillate oil and natural gas are not necessary since it was shown that emission rates, at near rated capacity, are considerably less for those fuels than for residual oil (i.e., residual oil is the worst case). The residual oil limits are determined as follows:

Annual fuel throughput limit for NO_x and CO:

NO_x = (96.64 lb/1000 gal)(X)(ton/2000 lb) = 198 tons/yr

X = (198 tons/yr)(1000 gal/96.64 lb)(2000 lb/ton) = 4,097,682 gal/yr

Short term fuel throughput limits for PM_{10}:

X = (239 gal/hr)(24 hr/day) = 5736 gal/day for Boiler 1

X = (402 gal/hr)(24 hr/day) = 9648 gal/day for Boiler 2

Since the emission factor is the same for both boilers, a combined fuel throughput limit of 15,384 gal/day is used in the permit (5736 + 9648 = 15,384).

The operating limits for Boiler 3, and corresponding monitoring in Section 4 of the permit, were changed so they are now based on fuel consumption instead of hours of operation. This change does not result in a change in operations for Boiler 3. The fuel consumption limits were determined as follows:

Distillate oil = (1440 hr/yr)(273 gal hr) = 393,120 gal yr

Natural gas = (8568 hr/yr)(39 MMBtu/hr)(scf/1020 Btu) = 328 MMscf/yr

Permit Condition 3.4

The compliance demonstration provided in the application (e.g., NAAQS) was based on a worst case operating scenario where Boilers 1 and 2 are operated at a reduced firing rate using No.6 oil, and Boiler 3 is not operated. This permit condition was established to ensure that the facility continues to operate in a manner that will not exceed this worst case scenario. However, it will also provide flexibility by allowing Boiler 3 to operate when Boilers 1 and 2 fire residual oil as long as firing of the boilers does not exceed the assumptions presented in the application (i.e., 15, 384 gal/day of No. 6 oil in Boilers 1 and 2 and 80,000 lbs-steam per hour from all three boilers).

Permit Condition 3.5, 3.6, and 3.7

The permit requires that wet scrubbing treatment be provided for the exhaust from Boiler 1 and Boiler 2 when fuel oil is combusted. When natural gas is combusted there is no requirement for wet scrubbing.

The requirement to install operate a wet scrubber(s) when combusting fuel oil is based on BAF's use of a wet scrubber in the application to demonstrate acceptable ambient impacts and compliance with the PM standard for fuel burning equipment (IDAPA 58.01.01, Section 676). To ensure proper operation of the scrubbing system, the permit requires that equipment be provided to monitor critical scrubber operating parameters. The permit also requires that an O&M manual be prepared for the scrubbing system and that the scrubber be operated and maintained in accordance with the plan.

With regard to merging the exhaust of Boilers 1 and 2, BAF's demonstration of compliance with ambient air quality impact requirements assumed that the exhaust from Boiler 2 would be merged with the exhaust from Boiler 1 whenever wet scrubbing was provided (i.e., whenever fuel oil was combusted in Boiler 2). The merged exhaust would then be discharged through the existing Boiler 1 stack. Because these operating conditions are part of BAF's NAAQS compliance demonstration, Permit Condition 3.5 requires that these exhausts be merged when wet scrubbing is provided.

Permit Condition 3.8

A permit condition requiring annual tune-up for each boiler was included in the previous permit as a method for demonstrating compliance with the emission limits that are based on efficient combustion practices. No substantive changes were made. provided.

Permit Conditions 3.9, 4.1, 4.2, 4.3, 4.4, 4.5, 4.10, 4.14, and 5.1

These permit conditions incorporate relevant portions of the NSPS compliance testing, monitoring, recordkeeping and reporting requirements that are applicable to sulfur dioxide and particulate emissions from Boiler 2 when combusting fuel oil. For sulfur dioxide, the permittee has the option of conducting monitoring either with a sulfur dioxide CEMS or by Method 6B. The PTC does not allow the permittee to monitor sulfur dioxide emissions using fuel supplier certification of distillate oil sulfur content for purposes of meeting the exemption requirements under 40 CFR 60 Part 64 (CAM).

For particulate matter, emission monitoring requires either a COMS or an approved alternate opacity monitoring plan. The NSPS requires a COMS, but COMS may not be a reliable monitoring method for exhaust that has been treated in a wet scrubber. Accordingly, Permit Condition 4.5 provides the permittee an option of developing an alternate opacity monitoring plan. The alternative opacity monitoring plan must be approved by EPA before being implemented. If approved, provisions of the alternate opacity monitoring plan will replace permit provisions requiring a COMS and appropriate provisions.

<u>Permit Condition 4.6 and 5.2</u>

For purposes of streamlining the demonstration of compliance with applicable requirements for Boiler 1, BAF has requested that Boiler 1 be subject to the same requirements for opacity and SO_2, including the NSPS requirements, that apply to Boiler 2. This will simplify permit compliance and allow the same instrumentation and controls to be used for both Boiler 1 and Boiler 2. The NSPS requirements provide an excellent method to demonstrate compliance with DEQ emission limits for opacity and sulfur dioxide.

<u>Permit Condition 4.7 and 4.8</u>

Periodic particulate matter performance testing while combusting No. 6 fuel oil, in conjunction with annual boiler tuning required by Permit Condition 3.8, is used to demonstrate compliance with the PM emission limits of IDAPA 58.01.01.676-677. An initial test for Boiler 2 is required within 60 days of reaching the maximum production rate with No. 6 oil or within 180 days of permit issuance. An initial test is not required for Boiler 1 since PM emissions will be reduced by the new scrubber and it was recently tested successfully using similar fuel (1.5% sulfur No. 6 oil) without the benefit of a control device. The next test for Boiler 1 is due within 5 years after this last PM test.

<u>Permit Condition 4.9</u>

NO_x performance testing while combusting fuel oil, in conjunction with an annual fuel throughput limit and annual boiler tuning requirements in Section 3, are used to demonstrate compliance with the 198 TPY NO_x limit for the boilers, and to show that plant-wide point source NO_x emissions will not exceed 250 TPY.

The difference between the facility-wide NO_x PTE of 235 tons per year and the regulatory threshold of 250 tons per year provides a margin of safety in emission estimates. In addition, by using NO_x emission factors that assume worst case fuel nitrogen content and that are significantly higher than AP-42 numbers, BAF has provided an additional margin of safety to assure that the 250 ton per year threshold is not exceeded. With these margins of safety, performance testing for NO_x emissions once every five years is satisfactory.

<u>Permit Condition 4.11</u>

This condition contains recordkeeping requirements which correspond to, and are used to demonstrate compliance with, the operating requirement to perform annual boiler tune-ups.

<u>Permit Condition 4.12</u>

Monitoring and recordkeeping of boiler operating parameters such as fuel consumption and steam production as required under the existing permit is continued in this permit.

<u>Permit Condition 4.13</u>

Fuel supplier sulfur content recordkeeping requirements of the existing PTC are included in this PTC and were changed to be consistent with the Tier I permit. This monitoring is required for purposes of showing compliance with IDAPA 58.01.01.725-728, not for NSPS purposes.

Permit Condition 4.15

Recordkeeping requirements were added that are consistent with Tier I permit requirements. This includes a five-year retention period.

Permit Condition 4.16

To demonstrate proper operation of the scrubbing system, the permit requires monitoring and recordkeeping of critical scrubber operating parameters to show the system is being operated in accordance with the manufacturers and O&M manual specifications.

Permit Condition 5.3

Performance test reports are to be submitted to DEQ within 60 days after completion of the test. This increases the time allowed for submission of the reports as compared with the existing permit. The added time is provided to allow additional time for reviewing the test report before submittal. The 60-day period also is consistent with changes that DEQ has previously agreed to provide for reporting under the facility Tier I permit.

5.5 Tier I Permit Conditions Review

This section describes only those Tier I permit conditions that have been revised, modified or deleted as a result of this permit action. All other permit conditions remain unchanged. Where permit condition numbers are given, these numbers correspond to the proposed modified Tier I, unless stated otherwise.

Permit Cover Page

Both the permit no. and the Facility ID no. were included. Also, the permittee name and the responsible official were corrected as presented in the application.

Section 1, Permit Scope

PTC No. P-050301 was added to Permit Conditions 1.2 and 1.3, and the emissions control information was revised for Boilers 1 and 2. In Table 1.1, the first column name was changed to be "Permit Section." Table 1.2, Monitoring and Reporting Summary, was deleted in lieu or revising it since it is not consistent with the facility-wide section and requirements summary table information negotiated between DEQ and EPA for Title V operating permits.

Section 3, Boilers 1, 2, and 3

The entire Section 3 was revised as follows. The summary description was changed to be consistent with the current Tier I format and the revised PTC. Existing Permit Conditions 3.1 through 3.20 were removed and replaced by the new PTC conditions. Each condition in PTC No. P-050301 is an applicable requirement, and it was added to Section 3 unless it is addressed elsewhere in the Tier I permit (e.g., in the Tier I Facility-wide or General Provisions sections). Refer to the PTC Permit Conditions Review section above for details. Table 3.3, the Applicable Requirements Summary, was also revised to incorporate the new PTC requirements.

Section 8, Nonapplicable Requirements

The acronym "CAM" was added to the permit's Acronym list and as follows: "Part 64 Compliance Assurance Monitoring (CAM)." The definition given by Reason Code "g" was changed to read as follows: "the facility does not have any emissions units which are subject to CAM requirements, as determined under 40 CFR 64.2".

General Provision 16

General Provision 16 was changed to refer to IDAPA 58.01.01.387 through 397 to be consistent with the latest rule revisions.

General Provision 21

General Provision 21.b was changed to reflect the actual Tier I Annual Compliance Certification schedule. General Provisions 21.d.ii and iii were revised to be consistent with the latest rule revisions.

General Provision 24

General Provision 24 was changed to reflect the actual Tier I Semiannual Monitoring Report schedule.

6. PERMIT FEES

DEQ received $7500.00 from BAF on February 6, 2005 and $1000.00 on July 22, 2005 for the PTC. Of this amount, $1000 is applied toward the PTC application fee and $7500.00 is applied toward the PTC processing fee In accordance with IDAPA 58.01.01.224-225. A permit to construct processing fee of $7,500 is due in accordance with IDAPA 58.01.01.225 because this project is a non-major modification to an existing source with an emissions increase exceeding 100 tons per year. Therefore, no additional fees are due before the PTC may be issued in accordance with IDAPA 58.01.01.226.02.

The BAF Blackfoot facility is a major facility as defined in IDAPA 58.01.01.008.10. Therefore, registration fees are applicable in accordance with IDAPA 58.01.01.387. As of July 12, 2005, no Tier I fees are overdue.

Table 6.1 PTC PROCESSING FEE TABLE

Fee Table			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emissions Change (T/yr)**
NO_x	147	0	147
SO_2	0	60	-60
CO	34	0	34
PM	7	0	7
VOC	2	0	2
TAPS/HAPS	2	0	2
Total:	192	60	132
Fee Due	**$ 7,500.00**		

7. PERMIT REVIEW

7.1 Regional Review of Draft Permit

Copies of the facility-draft PTC and Statement of Basis were provided to the Pocatello Regional Office for review on May 27, 2005 and a response was received on June 3, 2005.

7.2 Facility Review of Draft Permit

Copies of the modified draft PTC and Statement of Basis were provided to BAF on June 24, 2005. Comments were received from BAF on July 8, 2005 and July 11, 2005. The documents, including the

Tier I permit, were revised as appropriate and the changes are described in the Permit Conditions Review sections above.

7.3 Public Comment

A 30-day public comment period on the modified draft PTC and Tier I operating permit will be held in accordance with IDAPA 58.01.01.209.05.b.iii and 58.01.01.364. A notice will be published in the local newspaper and copies of the proposed action will be placed in the local area in accordance with these rules.

8. RECOMMENDATION

Based on review of application materials, and all applicable state and federal rules and regulations, staff recommend that Basic American Foods be issued drafts of PTC No. P-050301 and Tier I No. T1-050308 for the Blackfoot facility. A comment period will be scheduled and the project does not involve PSD requirements.

KH/sd Permit No. P-050301 and T1-050308

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